Optimal Transmission Tariff Regulation for the Southern Baja-Californian Electricity Network System

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AUTHOR´S MANUSCRIPT

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Abstract

The tariff imposed over the use of electricity transmission networks is one critical factor to achieve efficiency in electricity markets. In Mexico, the current transmission network tariffs are based on long run marginal costs. We propose an incentive price-cap mechanism and apply it to the meshed network system in the isolated electricity system of Southern Baja California, Mexico. We further compare the current transmission tariffs set by the Mexican regulator (CRE) with the tariffs resulting from our regulatory scheme. We show that our mechanism prices the network at tariffs rendering superior welfare compared to the tariffs determined by Mexican authorities.

Key words: Financial transmission rights, nodal prices, congestion management, electricity, Mexico.

JEL codes: L50; L94; Q40

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1. Introduction

One key objective in an electricity market is to achieve economic efficiency in the provision of its various services and products.[4] However, factors hindering this goal include incomplete markets, increasing trade of electricity among control areas, construction of new generating capacity that exceeds network capacity of the network, scarce operation and maintenance, poorly defined property rights, as well as lack of investment for expanding transmission networks. In last years, different authors have deepened into the study of electricity transmission expansion. The aim has been to find the optimal determination of network pricing and corresponding adequate regulation. This approach has gained importance, both in theory and practice, due to the liberalization processes in several electricity systems that prioritize vertical separation and unbundling of electricity generation and transmission, together with independent system operators (ISOs). The aim has been to create highly competitive electricity markets that facilitate timely infrastructure investment. Electricity transmission-network pricing is further especially important for generation supply companies to reach optimal efficient supply.

Mexico is currently opening its electricity industry to private investment in new generation and transmission projects so as to provide cheaper and more reliable electricity services to consumers.[5] This is being carried out through vertically disintegrating generation from transmission networks, and through granting an independent role to the system operator, CENACE. After the approval of the electricity reform in 2014, transmission tariffs are now based on long-run marginal costs through a methodology designed by the Mexican energy regulator (CRE). Such a tariff regulatory approach, however, might not generate sufficient efficiency incentives for the transmission network owner (CFE) to expand networks.

[4] See Hogan (2002) and Hunt (2002).
[5] See Secretaría de Gobernación (2016).

The issue of optimal transmission expansion has been analyzed in the economics literature through a range of different regulatory schemes and mechanisms, e.g., Léautier (2000), Vogelsang (2001), Rosellón (2003), Kristiansen and Rosellón (2006), Rosellón (2007), Tanaka (2007), Léautier and Thelen (2009), Rosellón et. al. (2010) and Hogan et al. (2010). Designing optimal regulatory mechanisms is difficult given the specific physical characteristics of electricity networks like negative local externalities due to loop flows, i.e. electricity flows obeying Kirchhoff's laws.[6] One approach to transmission expansion has been traditional central planning, either carried within a vertically integrated utility or by a regulatory authority. A usual alternative has been cost-of-service regulation. In contrast, transmission decisions could also be determined in a decentralized non-regulated way.

The Hogan-Rosellon-Vogelsang price-cap mechanism (Hogan et al. 2010, HRV) is an example of a decentralized regulatory regime which combines merchant and regulatory structures to promote the expansion of electricity networks. The HRV incentive mechanism has been shown to promote network expansion in a welfare superior way to cost-plus regulation or no-regulation in a number of analytical studies, even under realistic demand patterns and large-scale renewable integration (e.g., Rosellón and Weigt, 2011, Rosellón et al., 2012, Ruiz and Rosellón, 2012, Zenón and Rosellón, 2012, Schill et al., 2015, Egerer et al., 2015, Neumann et al., 2015).

In this paper, we propose an incentive price-cap mechanism over the two-part tariffs of the transmission company (Transco), which promotes welfare efficient expansion of the transmission grid. We apply our mechanism to the isolated network system in Southern Baja California, Mexico. We further compare in terms of consumer surplus, by means of simulations,

[6] See Schweppe et. al. (1988)

the CRE's tariffs with the tariffs resulting from our model. Our proposed model relies on HRV, a model that has also been tested in several real electricity networks, and proved to achieve network price convergence to welfare-optimal Ramsey tariffs. Welfare-optimal expansion of the Baja Californian grid is addressed in our paper under the new nodal pricing system implemented in the Mexican system.

This document is organized as follows. In first instance, in section 2 we present a brief description of the Mexican electricity sector enumerating the activities taking place within the industry, summarizing the characteristics of the current infrastructure in the electricity system, and pointing out the regulatory regime currently in place for electricity networks. In section 3, we present the model for transmission expansion, and we describe the data and sources from the Baja Californian system used, the simulations carried out, as well as our main results. In section 4, we conclude with brief concluding remarks.

2. The Mexican Electricity Transmission System and Regulated Tariffs

2.1 The Mexican Transmission System and Prodesen

98.4% of the Mexican population has nowadays access to electricity through a grid of 879.691 kms. in length owned by CFE (transmission and distribution lines), and an infrastructure of 190 power plants yielding 41.516 megawatts (MW) in effective capacity. The generation park is comprised of 74.1% in fossil fuels (48,530 MW) and 25.9% in clean technologies (16,921 MW).[7] 83%[8] corresponds to power stations for public service, while the remaining 17%

[7] Clean energy technologies in Mexico include hydro and nuclear generation, as well as renewable energy sources (solar, wind, geothermal and biomass).
[8] 76% of generation capacity for public service corresponds to plants owned by CFE, and the remaining 24% plants are owned by Independent Power Producers (IPP's).

correspond to power private schemes such as self-supply, cogeneration, small contribution, exports, and continuous-own use.

The national transmission system is composed of 53 regions as shown in Figure 1,[9] 49 of which are interconnected and form the Interconnected Electricity System (IES); the remaining 4 regions conform a group in the isolated south region of Southern Baja California. The capacity of the connection between transmission regions remains in the range of 90MW to 4.000 MW. As of December 2014, the total length of transmission lines with voltage between 230-400 kV was 52.815 km, and 58.660 km for voltages of 69 kV.

Figure 1. National transmission system of Mexico

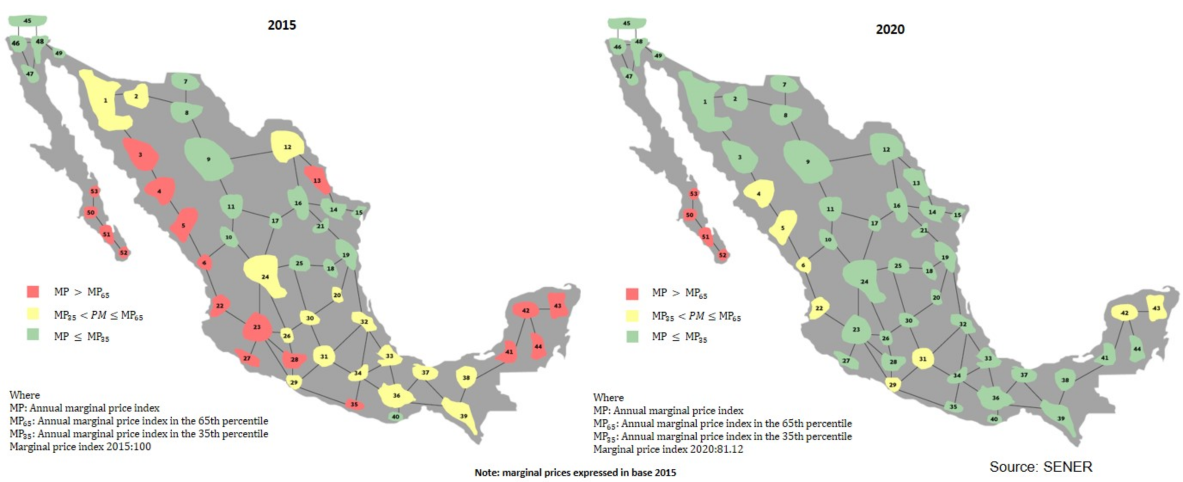
The modernization and expansion of the national electricity infrastructure is one of the objectives of Mexican authorities to boost economic development. In the context of the electricity reform, the aim is to anticipate the needs of the national electricity demand and supply growth through substantially expanding the national transmission system, including a future interconnection of the IES with the isolated network system in Southern Baja California. According to the national transmission planning system, PRODESEN, the IES is expected to

[9] Regions Ixtepec (40), Güémez (21) and Loreto (53) were incorporated into the national electricity system in 2015.

develop in such a way during coming years so that marginal prices in most areas of the country will become more uniform (see Figure 2).[10]

PRODESEN is actually carried out through a complex planning system, including a power-flow model to determine specific transmission-line expansion projects. Line expansion are determined using as input the forecast on future growth of generation plants throughout the country annually made by the energy ministry (SENER), Transmission expansion then follows generation growth in the logic of the PRODESEN's planning process. For 2015-2029, it is estimated that 24.599 kms. of new network capacity need to be built (see Appendix 1)[11].

Figure 2. Nodal pricing system's projection for 2020



Source: SENER

2.2 Regulated Electricity-Transmission Tariffs

CRE has recently determined a set of regulated transmission tariffs the period January 1st, 2016 through December 31st, 2018.[12] The information submitted to CRE by the CFE was analyzed taking

[10] The IES has been meshed in the voltage level of 400 kV in the center, east, northeast and west of the country. In the north, northwest and peninsular areas, the IES is in stage of strengthening, with transmission networks in some isolated links evolving from 230 kV to 400 kV. See SENER (2015)
[11] Appendix 2 presents the corresponding transmission expansion data for Southern Baja California.
[12] See CRE (2016a, 2016b, 2016c)

into account information of its audited financial statements, costs reported, the relevance of the cost-allocation model, as well as projections on demand and supply. The determination of regulated transmission tariffs consisted of two sequential steps. In a first step, the required income authorized to CFE for providing the electricity-transmission service is determined (adjusted with an efficiency factor). In a second step, the required income is allocated with tariffs to the different types of consumers. The formulas for each step are as follows:

First step

$$RI = C + OMA - X$$

where

RI: Required Income

C: Return on capital and depreciation

OMA: Operating, maintenance and administration costs [13]

X: Adjustment factor for efficiency improvements in operating OMA costs for 2017 and 2018 [14]

The RI for 2017 and 2018 will also be subject to the X-efficiency factor, as well as to inflation, exchange-rate and PRODESEN-investment factors. Table 1 below shows the RIs for 2016-2018 calculated by the CRE.

[13] OMA considers both historical and projected operating costs reported by CFE.
[14] An annual 1% X-efficiency factor was determined for 2017 and 2018.

Table 1. CFE´s required incomes for 2016-2017 (source: CRE)

Composition of income required			
Millions pesos			
	2016	2017	2018
operating costs	21 833	22 353	22 477
asset cost	22 854	22 425	22 549
Income Required	44 687	44 777	42 025

Second step

Since users of the national transmission network are generators, suppliers and qualified users, revenue allocation authorized to CFE is set proportionally to these types of consumers: 70% to consumers and 30% to generators. The design of charges is performed through a particular form of "postage stamp" based on injections or withdrawals of energy that each generator, supplier or qualified user make from the network. Weights are also assigned based on tension levels, so as to reflect the capacity long-run marginal costs (see Table 2). There are two voltage ranges: higher or equal to 220 kV, and below 220 kV. Marginal costs to develop these two types of networks are different, and there are consumers that that make use of both tension levels.

Table 2. Weighting factors for different voltage levels (source: CRE)

Weighting fcators for voltage level		
voltage level	**Generators**	**Consumers**
	interconnected generators	supply services
$\geq 220\ kV$	0.55	0.44
$< 220\ kV$	1	1

Based on the above weighting factors and the allocation of CFE’s transmission income, generation and load tariffs are calculated according to:

$$Td_{i,j} = \frac{70\%\ RI}{MWhd_{i,j} + MWhd_{k,j} * FPd_{i,j}}$$

$$Tg_{i,j} = \frac{30\%\ RI}{MWhg_{i,j} + MWhg_{k,j} * FPg_{i,j}}$$

where:

- $Td_{i,j}$: tariff for consumer *i* connected in tension level *j*.
- RI: annual net required income
- $FPd_{i,j}$: weighting factor for voltage level *i* to which demand *d* is connected
- $MWhd_{i,j}$: energy extraction of user *i*
- $MWhd_{k,j}$: energy demand of resting consumers *k*.
- $Tg_{i,j}$: tariff for generator *i* connected in voltage level *j*.
- $FPg_{i,j}$: weighting factor for voltage level *i* to which generation *g* is connected.
- $MWhd_{i,j}$: energy injection of generator *i*
- $MWhd_{k,j}$: total generation injected into the grid for resting generators *k*.

In accordance with projected demand, CRE has determined transmission tariffs for 2016 as shown in Table 3.

Table 3. Electricity transmission tariffs in Mexico (source: CRE)

Transmission tariffs of electricity		
voltage level	**Generators**	**Consumers**
	interconnected generators	supply services
$\geq 220\ kV$	0.0499	0.0625
$< 220\ kV$	0.0904	0.1424

Notes:
1. Tariffs for generators apply to all generators participating in the wholesale electricity market, and to energy injections in the first point of interconnection of the national territory associated with imports.
2. Tariffs for consumers apply to all qualified users who are market participants, retailers, and marketers who purchase energy in the wholesale electricity market, and energy extractions in the last point of connection of the national territory associated with country exports.

At the end of a tariff period, a reconciliation of the required income authorized to CFE will be made. Income in excess or less than the authorized income will be transferred to the next tariff period. In addition, tariffs are updated annually by applying, in the corresponding year, an inflation-production-price adjustment factor and the average daily exchange rates[15] observed during the year for which the adjustment is being made. For these adjustments, it is assumed that total CFE's costs are affected 10% by exchange-rate variation 90% by domestic inflation.

3. The Model, Data, Simulations and Results

3.1 The Model

Our model is based on the two-level programming model in Hogan et al. (2010). More specifically, we use the "capacity setting" version of this model[16] that enables the Transco to choose its network capacity and its fixed fees, while maximizing its flow of profits when expanding the network.[17] For the reader's convenience, we make in the Appendix a transcription of this model.

This mechanism is applied to the Baja Californian transmission system assuming linear inter-node transmission cost-functions, expanding cost values, a linear demand with a price–elasticity value of at each reference node, and a depreciation factor. A price cap is then set over the transmission two-part tariff weighted by previous period *Laspeyres* weights. Hourly results obtain as outcomes.

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[15] Based on the exchange rate to settle liabilities denominated in dollars E.U, payable in Mexico published in the Official Gazette, by Bank of Mexico.

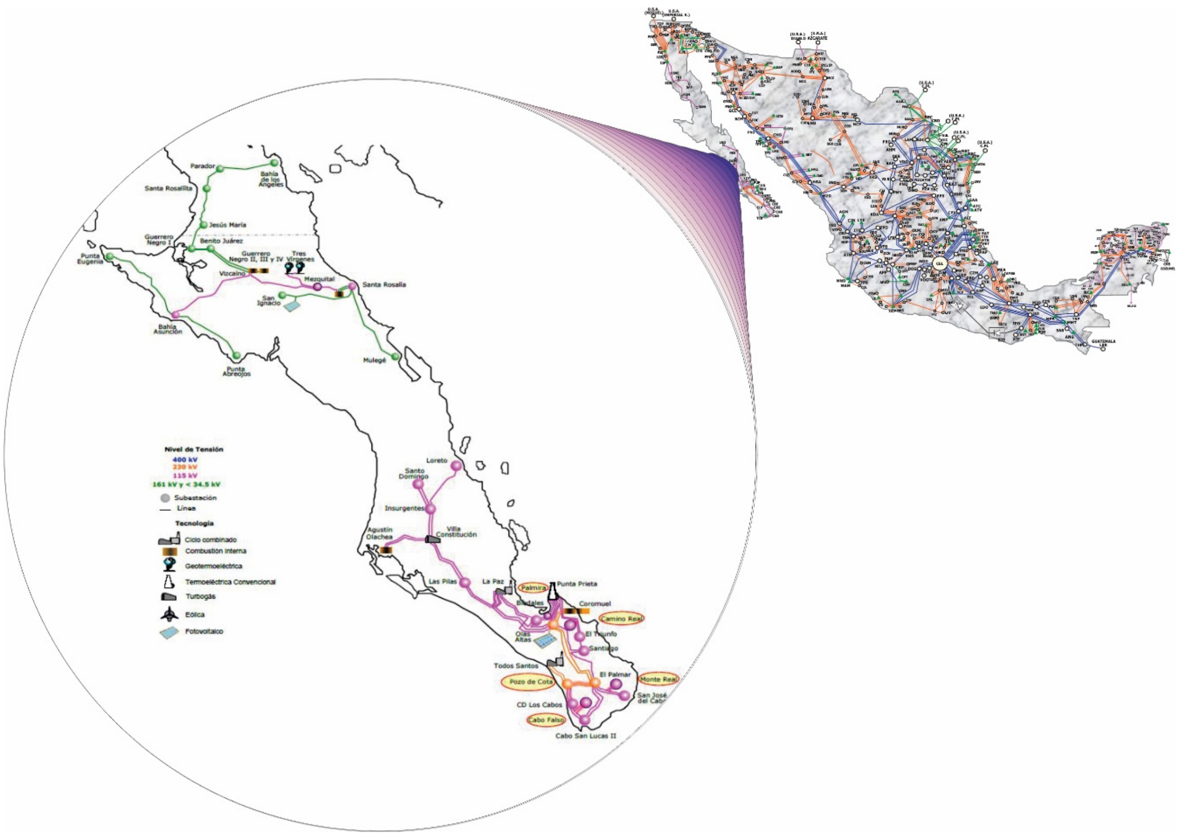
[16] See Hogan et al. (2010), section 6.2.3.

[17] The original choice variables in the HRV model are incremental financial transmission rights FTRs (variable part) and the fixed part of the transmission two-part tariff (Hogan et al., section 6.2.1). For implementation purposes, this original reformulation can be reduced in terms of the congestion rent collected by the ISO, given market clearing prices (FTRs stand for financial transmission rights, a financial instrument used in electricity markets to hedge consumers from nodal-price instruments. FTRs are also important to grant property rights in the expansion of transmission networks. See Joskow an Tirole, 2000, and Kristiansen and Rosellón, 2006, 2010. FTRs can also have important redistributive effects in recently created markets. See Kunz et. al., 2014).

3.2 Data

Data collected and used in this work correspond to the isolated electricity system of Southern Baja California, as shown in Figure 3. All existing lines in this system have levels less than or equal to 230 kV . Figure 3 also depict existing generation plants.

Figure 3. Isolated system of Southern Baja California (Source: Own elaboration)



3.3 Simulations and Results[18]

Two scenario analysis are analyzed:

1. The first one addresses the three nodes appearing in Figure 1 for Southern Baja California.

[18] The following simulations assume uniform congestion levels across transmission lines.

2. The second scenario case considers a disaggregation of these 3 nodes, taking into account an actual detailed infrastructure of 31 nodes (substations) contained in the isolated system.

Table 4 presents sources for the data required to run the HRV model for the two scenarios.

Table 4. Data and sources

LOWER-LEVEL AND UPPER-LEVEL MODELS	
DATA	SOURCE
Existing network, disaggregation of nodes: Case 1: 3 nodes Case 2: 31 nodes	SENER-PRODESEN (2014-2015) CENACE (2014-2015)
DEMAND NODE I / DEMAND NODE I PER HOUR FOR BOTH CASES	SENER-PRODESEN (2014-2015) CENACE (2014-2015)
Generation of node i / generation node i by hour and type of technology	SENER-PRODESEN (2014-2015) CENACE (2014-2015)
Generation costs by type of technology, for both cases.	CFE (2012)
MAXIMUM CAPACITY OF LINES, REACTANCE, LENGTH, ETC., FOR BOTH CASES	SENER-PRODESEN (2014-2015) CENACE (2014-2015)
REGULATED TARIFFS[19]	CRE (2016)
Contrast data as support for verification of results	SENER-PRODESEN (2014-2015)

3.3.1 Simulation Method

Simulations for the Southern Baja California system were implemented as an MPEC problem in the GAMS software.[20] Simulations are performed continuously over 10 periods. A congested network is assumed at the beginning of the simulation. The mechanism starts by solving the lower-level power-flow problem. Once this problem sheds feasible solutions for dispatch,

[19] As shown in Table 3.

[20] *Mathematical programming with equilibrium constraints* (MPEC) is a mathematical technique related to the *Stackelberg* games used to study constrained optimization problems subject to various types of constraints (e.g.,variational inequalities or complementarities). The *General Algebraic Modeling System* (GAMS) is a modeling system for mathematical optimization that solves linear, nonlinear, and mixed-integer optimization problems.

losses, energy flows and nodal prices, the profit maximization upper-level problem of the Transco subject to the incentive regulatory constraint is solved, using as inputs the results of the lower-level problem. A linear demand is assumed at each node.[21]

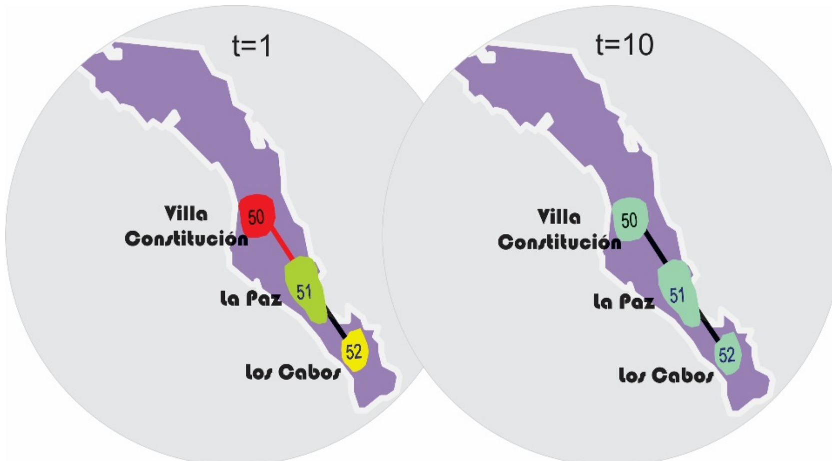
3.3.2 Case 1: 3 Nodes

This first case analyzes a network of three nodes, represented in Figure 4. These data are taken from information in aggregated form. Simulations run over 10 periods and results are illustrated in Figure 5.

Figure 4. Map Transmission regions of Baja California Sur (Source: Own elaboration)

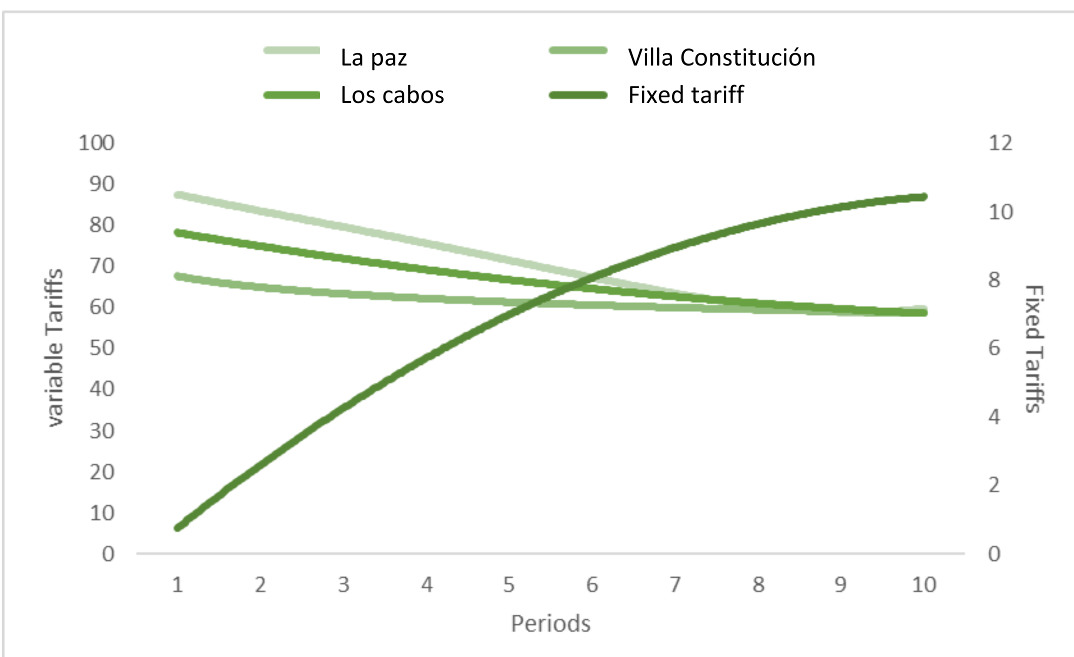
Figure 5. Comparison of results of the HRV mechanism for periods 1 and 10 (Source: Own elaboration)

[21] The linear demand function is a standard assumption in the applied literature of incentive regulation for electricity transmission. See for instance, Rosellón and Weigt (2011).



As shown in Figure 5, there is initially a congested transmission line. This line connects the transmission node of *Villa Constitución* with the node *La Paz*. Therefore, under this analysis, the Transco invests in such a congested line, increasing in transmission capacity. So as to counterbalance the loss in congestion rents, the Transco raises its fixed tariff relative to the variable part. Figure 6 shows these rebalancing over 10 periods. Capacity investments in the transmission network allow convergence of prices in all nodes to a single variable price.

Figure 6. Rebalancing fixed and variable tariffs for 3 nodes



3.3.3 Case 2: 31 Nodes

This case addresses data in a network with 31 nodes and 39 transmission lines as shown in Figure 7. Here, we count with more detailed information on the network; thus can be observed specific areas with congestion and thus make investments in specific lines that require it. Simulations over 10 periods were conducted with the following results:

Figure 7. Detailed nodal network system of Southern Baja California

(Source: Own elaboration)

As shown in Figure 8, there are initially various congested transmission lines. Red highlights the most congested lines, while green the least congested lines. It may also be observed that there exist lines that display no congestion. Figure 8 also shows another map with the realized investments after the various simulation periods[22]. This analysis permits to observe capacity

[22] Investment is shown in percentage relative to the initial capacity in the starting lines.

increases of congested lines over time. Again, the implied losses in congestion rents are compensated with increases in the Transco's fixed tariff. Another important result obtained is shown in Figure 9. As expected, there is a convergence in the nodal price to a marginal uniform price at the end of the simulation prices.

Figure 8. Congested network of Southern Baja California Sur and line investments over 11 periods (Source: Own elaboration)

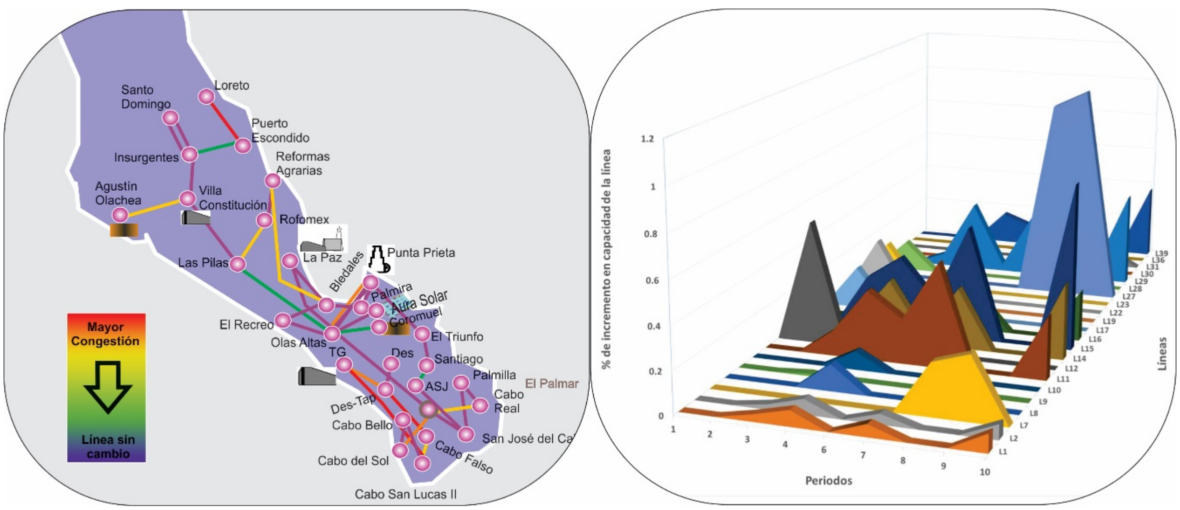
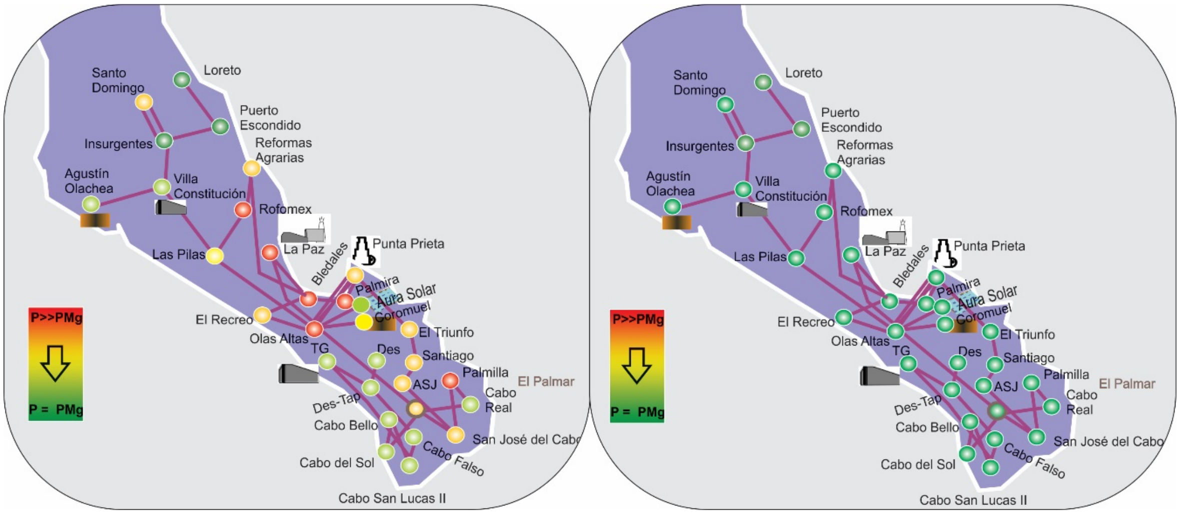
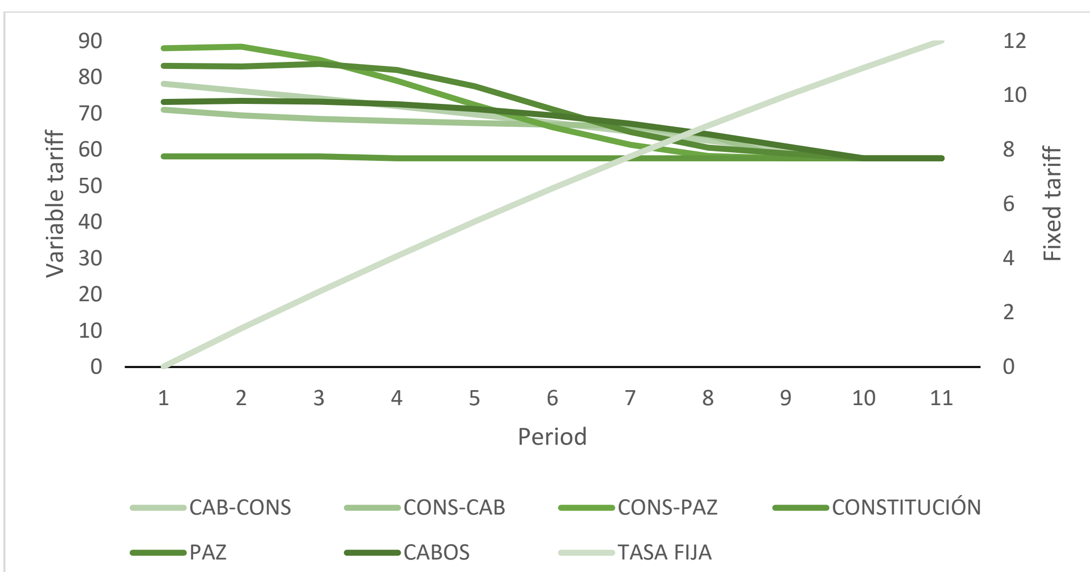


Figure 9. Convergence of nodal prices to a marginal uniform price (Source: Own elaboration)



As before, our model allows a convergence to marginal prices based on capacity investments on the network. The investment process is characterized by the rebalancing of the fixed and the variable tariffs, as shown in Figure 10.

Figure 10. Rebalancing of fixed and variable tariffs for the 31-node case



3.3.4 Tariff Comparisons

In our analysis, price zones are divided into 6 zones. Three of these areas represent the areas mentioned in case 1, and the other three areas represent the interconnections between the zones in Los Cabos, La Paz and Villa Constitución. Results lump together the prices in these 6 zones. We compute a transmission tariff for each of the periods of the simulation which allows the Transco to have the necessary incentives to invest in network expansion. This tariff is calculated by taking into account the fixed tariff resulting from our model as well as congestion rents. Additionally, we apply weights in the same way as the CRE's mechanism. That is, 70% is considered a charge to consumers, and 30% to generators. Tables 5 and 6 below indicate the results obtained for generators and consumers, respectively, when our calculated tariff (HRV) is compared to the CRE's one. We take the demand projected by the SENER for the next 10 years. The expected payoff for consumers with both tariffs is calculated. The savings or excess expenditure for consumers under our proposed HRV scheme is also obtained.

Table 5. Comparison of electricity transmission tariffs for generators.

ELECTRICITY TRANSMISSION TARIFFS FOR GENERATORS ($ / MWh)						
PERIOD	VOLTAGE <220 KV[23]		DEMAND* MWH	PAYMENT OF GENERATORS		HRV SAVINGS
	HRV	CRE		HRV	CRE	
1	66.19	90.40	486.50	32,202.56	43,979.60	11,777.04
2	80.01	93.65	511.28	40,907.07	47,883.19	6,976.12
3	91.38	97.03	541.65	49,494.88	52,553.85	3,058.96
4	98.88	100.52	571.15	56,475.86	57,410.87	935.01
5	103.65	104.14	602.41	62,439.76	62,733.93	294.17
6	106.72	107.89	639.69	68,264.76	69,013.88	749.13
7	109.78	111.77	680.13	74,661.26	76,017.97	1,356.72
8	112.89	115.79	724.51	81,792.94	83,893.99	2,101.06
9	116.04	119.96	773.11	89,713.57	92,744.26	3,030.69
10	123.40	124.28	821.54	101,375.99	102,102.49	726.50
11	134.57	128.76	877.68	118,113.07	113,005.72	-5,107.34

* Demand forecast for southern Baja California (provided by SENER)

[23] The analysis is performed only for lower voltages to 220 Kv given the data. As the BCS System 2015 had only 2 lines of 230 Kv and the remaining 37 lines with a lower voltage.

Table 6. Comparison of electricity transmission tariffs for consumers.

ELECTRICITY TRANSMISSION FOR CONSUMERS ($ / MWh)						
PERIOD	VOLTAGE <220 KV		DEMAND* MWH	PAYMENT OF GENERATORS		HRV SAVINGS
	HRV	CRE		HRV	CRE	
1	85.14	142.40	486.50	41,418.55	69,277.60	27,859.05
2	105.14	147.53	511.28	53,757.08	75,426.62	21,669.55
3	121.93	152.84	541.65	66,043.10	82,783.94	16,740.84
4	133.68	158.34	571.15	76,348.30	90,434.83	14,086.53
5	141.83	164.04	602.41	85,441.76	98,819.82	13,378.06
6	147.73	169.95	639.69	94,501.17	108,712.13	14,210.96
7	153.55	176.06	680.13	104,431.83	119,745.12	15,313.30
8	159.37	182.40	724.51	115,464.53	132,151.60	16,687.07
9	165.16	188.97	773.11	127,684.58	146,092.72	18,408.14
10	176.28	195.77	821.54	144,822.85	160,834.01	16,011.16
11	192.25	202.82	877.68	168,732.95	178,009.02	9,276.07

* Demand forecast for southern Baja California (provided by SENER)

Results then show that consumers' spending is less under our model. Figure 11 illustrates this.

Figure 11. HRV tariffs vs. CRE tariffs for generators and consumers

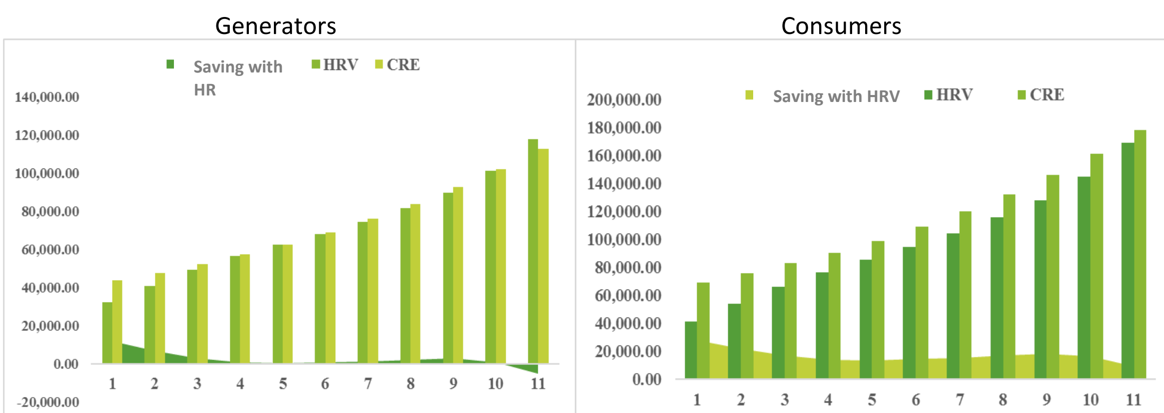


Figure 11 shows a lower tariff implied by our incentive model than that calculated by the CRE for both network users. It can also be noted that in the case of generators the tariff difference is not very significant. However, in the case of consumers the difference is quite large over all periods. This could indicate that the tariff being charged to consumers by the CRE is non-optimal.

4. Conclusions

This paper carried out the application of a hybrid merchant-regulatory mechanism so as to obtain transmission welfare-maximizing tariffs for the Southern Baja Californian electricity system. We further compared our obtained tariffs with the corresponding ones used by the Mexican regulator, CRE, to set the CFE's transmission prices. The CRE actually obtains these tariffs through a two-stage process. In the first stage, the CFE's required income is determined based on operation and maintenance costs, adjusted by efficiency and inflation factors. In the second stage, a weight is established depending on the tension level at which a network link is being used. This permits to reflect the long-run marginal costs of developing transmission links. Two types of tariffs are then obtained for each tension level. One for generators and another one for consumers. We showed that this CRE's mechanism does not result in welfare efficient pricing and, additionally, does not provide invectives to expand the network efficiently.

In contrast, our model proposes an incentive price-cap regulation regime over the CFE's Transco within a competitive nodal-price electricity market that is operated by an ISO (CENACE). Our price-cap formula really establishes a limit on the Transco's two-part tariff, relying on Laspeyres weights, and incents the expansion of the transmission grid through the rebalancing of the fixed and variable parts of the tariff. This process gradually diminishes congestion rents but the Transco is able to compensate the loss in such rents by increasing the fixed-part of the tariff, a process that inter-temporally eventually leads to convergence to a welfare optimal steady state. The transition to such state is also carried out in a way that both consumer and producer surpluses increase over time.

The comparison of our tariffs with the CRE's tariffs for Southern Baja California was done under two cases on nodal structure, using real data from CENACE. In a first aggregated case, we assumed a three-node market. In the second disaggregated case, a more detailed thirty-one node structure was modelled. The second case, of course, allows for more detailed results on planned capacity-increase for each transmission line in the system. In both cases, our regulated tariffs align better than the CRE's tariffs regarding investment incentives to efficiently expand transmission links as well as on eventually converging to optimal social welfare.

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6. Appendixes

6.1 Appendix 1: New Network Capacity for Southern Baja California (2015-2029)

7.1

INVESTMENT IN TRANSMISSION for VOLTAGE LEVEL 2015-2029. (IN MILLION PESOS)

year	400 KV	230 KV	161-69 KV	TOTAL
2015	2,101	422	1,753	4,276
2016	4,492	1,453	1,035	6,980
2017	4,138	1,293	2,662	8,093
2018	2,324	975	2,675	5,974
2019	3,833	882	2,559	7,274
2020	2,035	1,092	1,144	4,271
2021	919	754	1,058	2,731
2022	434	1,088	843	2,365
2023	508	904	528	1,940
2024	8,076	707	750	9,534
2025	7,690	570	627	8,887
2026	1,513	225	194	1,931
2027	466	520	87	1,073
2028	354	306	119	778
2029	777	350	133	1,261
Total	39,660	11,541	16,167	67,368

SOURCE: CENACE.

INVESTMENT IN TRANSFORMATION BY VOLTAGE LEVEL 2015-2029 (IN MILLION PESOS)

Año	400 KV	230 KV	161-69 KV	TOTAL
2015	1,286	1,726	4,239	7,251
2016	1,953	1,374	3,062	6,389
2017	2,561	2,523	3,195	8,279
2018	1,021	1,743	3,359	6,123
2019	1,017	1,417	3,989	6,423
2020	1,263	1,535	2,852	5,650
2021	589	1,230	1,818	3,637
2022	1,177	1,315	1,295	3,787
2023	945	1,036	982	2,963
2024	1,413	1,075	1,297	3,785
2025	1,586	669	1,173	3,428
2026	797	286	702	1,785
2027	495	386	159	1,040
2028	529	342	191	1,063
2029	607	338	351	1,296
Total	17,239	16,995	28,664	62,899

SOURCE: CENACE.

INVESTMENT IN COMPENSATION FOR VOLTAGE LEVEL 2015-2029 (IN MILLION PESOS)

Año	400 KV	230 KV	161-69 KV	TOTAL
2015	224	267	241	733
2016	608	117	195	919
2017	1,145	8	317	1,469
2018	422	19	444	885
2019	268	67	395	730
2020	184	62	242	488
2021	160	0	89	249
2022	32	0	131	163
2023	41	4	196	241
2024	443	15	169	627
2025	615	21	75	710
2026	121	0	29	150
2027	152	0	16	167
Total	4,612	579	2,597	7,787

SOURCE: CENACE.

6.2 Appendix 2: Transmission Expansion Data for Southern Baja California

CONSTRUCTION PROJECTS AND INDICATORS, 2015-2024, SOUTHERN BAJA CALIFORNIA

CONCEPT	Unit	Capacity
TRANSMISSION	Projects	16
	km-c	416.9
TRANSFORMATION	Projects	9
	Capacity MVA	810.0
COMPENSATION	Projects	10
	Capacity MVA	115.0

SOURCE: CENACE.

MAJOR SCHEDULED TRANSMISSION PROJECTS, 2015-2024, SOUTHERN BAJA CALIFORNIA

Transmission line	VOLTAGE KV	N° CIRCUITS	LENGTH KM-C	ENTRY DATE
Cabo Falso entronque Central Diésel Los Cabos - Cabo San Lucas II	115	2	0.2	JUN-15
Monte Real entronque Aeropuerto San José del Cabo -San José del Cabo	115	2	4.6	APR-16
Camino Real entronque Punta Prieta II- El Triunfo	115	2	2	APR-16
Pozo de Cota - El Palmar	230	2	54	APR-18
Pozo de Cota -Central Diésel Los Cabos	115	2	14	APR-18
Datilito (San Juan de la Costa) Derivación Olas Atlas	115	2	70	JUL-18
Derivación Olas Atlas -Olas Atlas1/	115	2	0.1	JUL-18
Derivación Olas Atlas -Bledales1/	115	2	6	JUL-18
Datilito (San Juan de la Costa) Derivación Olas Atlas	115	2	70	JUL-18
Todos Santos -Olas Atlas	230	2	120	OCT-18
Aeropuerto Los Cabos entronque Cabo San Lucas II- El Palmar	115	2	10	JUN-20
Aeropuerto Los Cabos - Los Cabos1/	115	2	18	JUN-20
Aeropuerto Los Cabos -Pozo de Cota1/	115	2	23	JUN-20
Libramiento San José entronque El Palmar Olas Atlas	230	2	2	JUN-21
Libramiento San José entronque El Palmar- San José del Cabo	115	2	20	JUN-21
Libramiento San José -Monte Real1/	115	2	3	JUN-21
Total			416.9	

SOURCE: CENACE

MAJOR SCHEDULED TRANSFORMATION PROJECTS, 2015-2024, SOUTHERN BAJA CALIFORNIA					
substation	**QUANTITY**	**EQUIPMENT**	**CAPACITY MVA**	**TRANSFORMATION RELATION**	**ENTRY DATE**
Cabo Falso Banco 1	1	T	30	115/13.8	Jun-15
Monte Real Banco 1	1	T	30	115/13.8	ABR-16
Camino Real Banco 1	1	T	30	115/13.8	Abr-16
Pozo de Cota Banco 1	4	AT	300	230/115	ABR-18
Palmira Banco 2	1	T	30	115/13.8	Jun-19
Aeropuerto Los Cabos Banco 1	1	T	30	115/13.8	JUN-20
Monte Real Banco 2	1	T	30	115/13.8	Jun-20
Libramiento San José Banco 1	4	AT	300	230/115	ABR-21
Cabo Falso Banco 2	1	T	30	115/13.8	Jun-21
Total			**810**		

AT. Autotransformer T. Transformer.

SOURCE: CENACE

MAJOR SCHEDULED COMPENSATION PROJECTS, 2015-2024, SOUTHERN BAJA CALIFORNIA				
COMPENSATION	EQUIPMENT	VOLTAGE KV	CAPACITY MVAR	ENTRY DATE
Bledales MVAr	Capacitor	115	12.5	Oct-17
Santiago MVAr	CAPACITOR	115	7.5	OCT-17
Cabo Real MVAr	Capacitor	115	7.5	Abr-19
Palmilla MVAr	CAPACITOR	115	7.5	ABR-19
San José del Cabo MVAr	Capacitor	115	15	Abr-19
Villa Constitución MVAr	CAPACITOR	115	7.5	ABR-19
Monte Real MVAr	Capacitor	115	12.5	Abr-19
Insurgentes MVAr	CAPACITOR	115	7.5	ABR-19
Loreto MVAr	Capacitor	115	7.5	Abr-19
El Palmar MVAr	CAPACITOR	115	30	ABR-20
Total			**115**	

PRODESEN 2015

SOURCE: CENACE**.**

6.3 Appendix 3: The HRV Model

The transmission two-part tariff is capped with a price cap (adjusted by rpi-inflation and x-efficiency factors) defined by the regulator. In general terms, the expansion of the network occurs in a such a way that congestion is reduced. This of course might have an initial effect of reducing the Transco's profits due to the reduction of congestion revenues. However, the Transco overcomes such a decline in congestion revenues by intertemporally rebalancing the two parts of its tariff, mainly increasing the fixed part. The sequence of actions in our model are described as follows:

- There is an existing network in an electricity market under a nodal-pricing design, and real power flows.
- There is a single Transco, which has a natural monopoly in the transmission network, and thus decides on the extension of the network.
- There is information on historical market prices. This information is used by the regulator to set a price-cap restriction over transmission two-part tariffs.
- Based on available market information on demand, generation supply, and network topology, the transco identifies which lines should be expanded.
- The iso manages generation dispatch maximizing welfare --collecting bids from generators and loads at each node-- and it calculates nodal prices. According to marginal nodal prices, the iso gathers payments from suppliers and pay generators. The difference between the two values represents the congestion rent of the system.
- The non-myopic Transco intertemporally maximizes profits according to the price-cap restriction on its two-part tariffs, rebalancing the variable and fixed parts of its tariff, and guided by the evolution in congestion rents.

- The choice variables are line capacity *k*, and the fixed tariff *f*.

Our model then consists of a sequence of two problems: an upper-level problem and a lower-level problem that are solved simultaneously. The upper-level problem consists of the maximization of profits by the Transco, subject to the price-cap regulatory constraint. The lower level problem is the ISO's power-flow optimal dispatch model in the wholesale market, which maximizes the social welfare.

We next present the upper-level and lower-level components of our model. The definition of variables is as follows:

k_{ij}^{t} = line capacity between node *i* and node *j* at time *t*.

F^{t} = fixed fee at time *t*.

d_{i}^{t} = demand at node *i* at time *t*.

g_{i}^{t} = generation at node *i* at time *t*.

g_{i}^{max} = available generation capacity.

N^{t} = number of consumers at time *t*.

$p(.)$ = demand function.

c(k) = transmission cost function in terms of capacity.

RPI = inflation adjustment factor

X = efficiency adjustment factor

w = weight

mc_{i} = marginal generation costs at node *i*.

pf_{ij} = power flow on the line connecting *i* and *j*

q_{i} = net injections

Upper-level problem

The Transco's objective is given in terms of congestion rents as:

$$\max_{k,F} \boldsymbol{\pi} = \sum_{i}^{T} \left[\overbrace{\sum_{i} p_{i}^{t} d_{i}^{t} - p_{i}^{t} g_{i}^{t}}^{A'} + \overbrace{F^{t} N^{t}}^{B} - \sum_{i,j} \overbrace{c(k_{ij}^{t})}^{C} \right] \tag{1}$$

Subject to

$$\overbrace{\frac{\sum_i (p_i^t d_i^w - p_i^t g_i^w) + F^t N^t}{\sum_i (p_i^{t-1} d_i^w - p_i^{t-1} g_i^w) + F^{t-1} N^t}}^{D\prime} \leq \overbrace{1 + RPI + X}^{E} \tag{2}$$

In (1), congestion rent *A'* depends on nodal-price differences between loads and generators: $\boldsymbol{p_i d_i - p_i g_i}$. Term *B* denotes revenues from fixed charges, while term *C* represents the expanding transmission cost function. (2) represents the RPI-X weighted price-cap constraint (*E*) over the transmission two-part tariff (*D'*).

Lower-level problem

An ISO maximizes social welfare *W* given restrictions on generation capacity, transmission-line capacity, and energy balance. It also makes sure that all electricity-engineering technical restrictions are met in a market with linear demand and constant generation marginal cost at each period *t*. The welfare maximizing problem for the ISO then looks like:

$$\max_{d,g} W = \sum_{i,t} \left(\int_0^{d_i^t} p(d_i^t) \mathrm{d}d_i^t \right) - \sum_{i,t} mc_i \, g_i^t \tag{3}$$

subject to

$$g_i^t \leq g_i^{tmax} \; \forall i, t \tag{4}$$

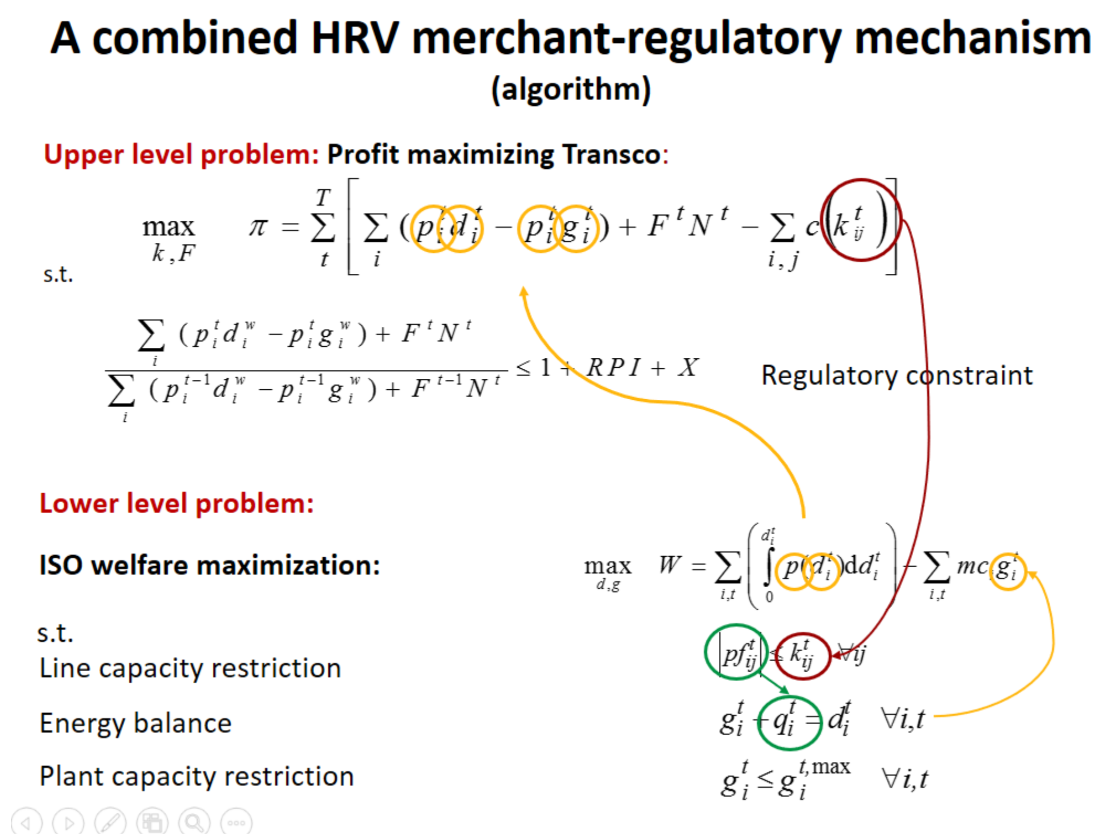
$$|pf_{ij}^t| \leq k_{ij}^t \; \forall i, j \tag{5}$$

$$g_i^t + q_i^t = d_i^t \tag{6}$$

Restriction (4) means that generation *g* at each node *i* cannot be greater than a predetermined maximum generation capacity $g^{\max}$. Equation (5) shows that energy flow pf_{ij} in a transmission link between nodes *i* and *j* may not exceed transmission-line limit k_{ij}. Last restriction (6) indicates that load at each local node is to be satisfied by generation supply at such a node, or from power imports from other nodes.

We follow the approach of an economic dispatch within a meshed dc-network topology. The Transco maximizes profits at each time *t* relying on the welfare-optimal solution derived from the ISO's economic dispatch program. Numerical iterations in the lower-level problem provide the optimal values of demand *d*, generation *g* and nodal prices *p* at each node *i*, which in turn feed up the upper-level program so as to determine the values of capacity *k*, and the corresponding fixed charge *f* (see figure 12).

Figure 12



SOURCE: OWN ELABORATION.